
APPLICATION FOR UNITED STATES LETTERS PATENT

for

**DRILL STRING DESIGN METHODOLOGY FOR
MITIGATING FATIGUE FAILURE**

by

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RELATED APPLICATION

This application claims the priority of prior provisional U.S. patent application Serial No. 60/464,794, filed on April 23, 2003, which application is hereby incorporated by reference in its entirety.

FIELD OF THE INVENTION

The present invention relates generally to the field of hydrocarbon production (i.e., the drilling of oil and gas wells), and more particularly relates to the design and operation of drill strings used in such production.

BACKGROUND OF THE INVENTION

Drill pipe is the principal tool, other than a drilling rig, that is required for the drilling of an oil or gas well. Its primary purpose is to connect the above-surface drilling rig to the drill bit. A drilling rig will typically have an inventory of 10,000 to 25,000 feet of drill pipe depending on the size and service requirements of the rig. Joints of drill pipe are connected to each other with a welded-on tool joint to form what is commonly referred to as the drill string or drill stem.

When a drilling rig is operating, motors mounted on the rig rotate the drill pipe and drill bit. In addition to connecting the drilling rig to the drill bit, drill pipe provides a mechanism to steer the drill bit and serves as a conduit for drilling fluids and cuttings. Drill pipe is a capital good that can be used for the drilling of multiple wells. Once a well is completed, the drill pipe may be used again in drilling another well until the drill pipe becomes damaged or wears out. It is estimated that the average life of a string of drill pipe is three to five years, depending on usage, and that an average rig will consume between 125 to 175 joints (3,875 to 5,425 feet) per year under normal conditions.

1 Drill collars are used in the drilling process to place weight on the drill bit for
2 better control and penetration. Drill collars are typically located directly above the drill bit
3 and are typically manufactured from a solid steel bar to provide necessary weight.

4 So-called "heavy weight drill pipe" or "HWDP" is a thick-walled, preferably
5 seamless tubular product that is less rigid than a drill collar, but more rigid than standard
6 drill pipe. Those of ordinary skill in the art will appreciate that heavy weight drill pipe can
7 be provided in a drill string to provide a gradual transition zone between the heavier drill
8 collar and the lighter drill pipe. It is generally recognized by those of ordinary skill in the
9 art that when heavy weight drill pipe is not used, the drill pipe near the top of the drill
10 collars may be unduly susceptible to fatigue damage and possible failure. Further details
11 regarding the use and characteristics of heavy weight drill pipe are set forth in U.S.
12 Patent No. 6,012,744 to Wilson et al., entitled "Heavy Weight Drill Pipe," which reference
13 is hereby incorporated by reference herein in its entirety.

14 Among the known considerations in the construction of a drill string is to ensure
15 that it is constructed in a manner which results in it remaining intact, functional, and free
16 from leaks during operation. Pump rates, pressure losses, annular velocities, and flow
17 regimes must accommodate all drilling requirements, while staying within pressure and
18 flow rate limitations imposed by the hole, the rig pumps, and surface equipment. The
19 components in the drill string must enable steering the bit in the desired trajectory, and
20 must accomplish the monitoring and measurements required for the hole interval being
21 drilled. Finally, the drill string should be configured to accomplish operating needs with
22 the lowest possibility of becoming stuck, and to possess the best chance of recovery,
23 should it become stuck.

1 Those of ordinary skill in the art will appreciate that a drill string design that
2 meets all needs for structural soundness must also take the likely failure mechanisms
3 into account. There are three failure mechanisms that are generally regarded as
4 accounting for a majority all structural failures: overload, fatigue, and sulfide stress
5 cracking ("SSC").

6 Overload refers to situations in which a component in the drill string is subjected
7 to loads that exceed its rated capacity.

8 Fatigue refers to progressive, localized permanent structural damage that occurs
9 when a component undergoes repeated stress cycles, even if such stresses are well
10 below the component's yield strength. The cyclic stress excursions most often occur
11 when a component is rotated while it is bent or buckled, and by vibration. As the loads
12 on the component cycle up and down, fatigue damage accumulates at high stress points
13 in the component, and fatigue cracks form at these points. Such cracks may grow under
14 continued cyclic loading until failure occurs.

15 Finally, sulfide stress cracking is a process in which steel, under tensile stress,
16 cracks in aqueous fluids in the presence of hydrogen sulfide (H_2S). Several sources of
17 hydrogen sulfide have been identified, though the source of principle concern is
18 formation fluids.

19 Compared to overload and SSC, fatigue damage and failure is far more difficult
20 to manage by design. The mechanisms of fatigue are very complex. Fatigue is driven by
21 point stress, or the stress in and around each geometric discontinuity, or stress
22 concentrator, on the string components. The effects of stress concentrators can be very
23 pronounced, and are difficult to evaluate with accuracy. Furthermore, drilling mud

1 corrosiveness significantly affects fatigue behavior. Finally, since fatigue damage is
2 cumulative, component history is extremely relevant for fatigue life prediction, but
3 methods for tracking component history in meaningful terms are at best gross
4 approximations. (As used herein, the term "fatigue life" will be understood to have its
5 commonly understood meaning in the industry, namely, the amount of time that a
6 particular component can be reasonably expected to operate under specified conditions
7 before suffering fatigue failure. Because it is a prediction of future events based only on
8 the available data, which may be incomplete or imprecise, there is an inherent element
9 of uncertainty in any quantification of "fatigue life" for any given component.
10 Nevertheless, assuming sufficient, reasonably accurate data is available, a quantification
11 of "fatigue life" for a particular component can provide a reasonably meaningful
12 indication of probable performance of that component.)

13 Fatigue mechanisms are so complex and the important variables (such as point
14 stress, environment, and history) are so little understood, relatively speaking, that
15 predictive models, on an absolute basis, have heretofore been found to be of little value.
16 That is, given the uncertainty of inputs combined with the complexity of the mechanisms,
17 the accuracy of predictive formulas is typically not good enough to form the basis for
18 design decisions. As a result, there is a tendency in the industry not to emphasize
19 fatigue failure mechanisms in the design and composition of drill strings.

20 Currently, the selection of the components used in the construction of a well has
21 been dictated by standard practices. Thus, a bottomhole assembly or a particular drill
22 string or heavy weight drill pipe string has been specified for a drilling application simply
23 because it met an industry practice or standard. The question of whether the particular

1 drilling component is the best available component for a particular application is not
2 necessarily addressed in the selection process. A difficulty in specifying the best of the
3 available components to be used in the drilling application is that there have been no
4 objective criteria for evaluating the capabilities of the individual components, particularly
5 as it relates to such components' fatigue resistance.

SUMMARY OF THE INVENTION

Notwithstanding the limitations of predictive modeling in designing drill strings that are optimally resistant to fatigue damage and failure, it is nevertheless deemed desirable to achieve drill string designs that are as fatigue resistant as possible. Accordingly, the present invention is directed to a drill string design approach which utilizes a "comparative approach" in the selection of drill string components. It is believed that the comparative approach in accordance with the present invention can lead to dramatic reductions in fatigue-related problems.

In accordance with one aspect of the invention, a method is provided for establishing objective criteria for evaluating individual components of well construction equipment to determine the preferred component or collection of components to be used from the selection of components available. As used herein, the terms "well construction " and "well construction equipment" are intended to include the procedures and equipment used in the drilling and completion of a well.

The method of the present invention provides new design constraints that may be used, for example, by a drilling engineer to make a selection of drilling equipment for a drill stem to be used in drilling a particular well. As a specific example, an objective of the new design constraint is to provide a means for a drilling engineer to compare the fatigue performance of a heavy weight drill string used in drilling a wellbore having a specified wellbore diameter to a standard or to an alternative heavy weight drill string.

A practical application of the new procedure is that a drilling engineer who has a string of heavy weight drill pipe available as a part of the drilling contractor's equipment can determine whether it is more efficient to use the available heavy weight drill pipe or to incur the additional cost of renting a special heavy weight drill pipe string that has a

1 longer fatigue life in the anticipated application. In some cases, it may be more
2 economical to rent a drill string rather than use the drill string supplied by the drilling
3 contractor because the fatigue life of the contractor's heavy weight drill pipe is
4 significantly less in the anticipated application than that available with a different size
5 heavy weight drill pipe string that must be rented from a third party.

6 Since a drill string designer almost always performs his or her function by
7 selecting from various alternatives, the comparative approach in accordance with the
8 presently disclosed embodiment of the invention involves (1) selecting the design
9 alternative and operating approach that provides the lowest stress excursion; (2)
10 selecting the design alternative offering the lowest stress concentration; and (3)
11 selecting the design alternative offering the best comparative fatigue life; and (4)
12 monitoring and reducing corrosion rates in mud systems.

13 In accordance with one aspect of the invention, a number of design and
14 operating parameters are quantified as "fatigue indices," and a predetermined set of
15 design constraints are imposed upon these indexes.

16 In one embodiment, a plurality of quantifiable design parameters relevant to the
17 issues of fatigue damage and failure of drill string components are defined, and an
18 assessment of each of these parameters is made for two or more candidate
19 components being considered for inclusion in the drill string. A comparison is then
20 made between the candidate components' ratings, and a decision to include or exclude
21 a candidate component is made based upon the results of such comparison.

22 Among the design parameters defined in accordance with the presently preferred
23 embodiment of the invention are: "Curvature Index," "Stability Index," and "Bending

1 Tolerance Rating.”

2 Drill pipe is rotated through dog legs in a process that causes the pipe to be
3 rotated around a bend. A primary objective of the Curvature Index is to permit
4 comparison of the relative fatigue life of drill pipe under different dog legs and tension
5 loadings during rotation.

6 In one embodiment, the Curvature Index (“CI”) gives a measure of the relative
7 reduction in fatigue life caused by variations in hole curvature, pipe diameter weight,
8 and grade, and axial tension in the pipe. Using the Curvature Index allows the designer
9 to quantitatively compare expected fatigue lives at various points in a given string, or
10 between alternative design choices in a given hole section. Another advantage of using
11 Curvature Index in drill string design is that it can form the basis for setting inspection
12 frequency and acceptance criteria.

13 In a practical application of the use of the Curvature Index, a drilling engineer
14 may have a choice of wellbore trajectories that may be used for reaching a subsurface
15 objective. For example, the trajectory may involve a wellbore that results in a 3° per
16 100 ft. dog leg with 450,000 lbs tension in the drill string or the wellbore may result in a
17 15° per 100 ft. dog leg with 100,000 lbs tension in the drill string to reach the same
18 objective. Drilling the well with a 3° per 100 ft. dog leg may be less costly than drilling
19 the well with a 15° per 100 ft. dog leg. However, the reduced fatiguedamage done to
20 the drill pipe during the drilling of the 15° per 100 ft. dog leg well may offset the savings
21 associated with drilling the 3° per 100 ft. dog leg well The Stability Index (“SI”) is a
22 measure of the relative fatigue life of bottomhole assemblies (BHAs) that are subjected
23 to being simultaneously buckled and rotated. The Stability Index is useful for comparing

1 one design alternative with another to select the alternative most favorable from a
2 fatigue standpoint. More specifically it is used to compare various drill collar and HWDP
3 sizes run in various hole sizes. Having selected a BHA design, the designer can also
4 use the Stability Index to estimate the fatigue resistance of the BHA for the purpose of
5 setting inspection intervals.

6
7 Further in accordance with the present invention, the Bending Tolerance Rating
8 ("BTR") is a rating system useful for rating stress effects of a collared component or
9 downhole tool based on the maximum stress levels recorded in the drill string, including
10 stress concentrators.

11 The Bending Tolerance Rating is used to assist in the selection of bottomhole
12 assembly components that may have an unusual or special configuration with structural
13 capabilities and limitations that are not commonly known to the design engineer. In one
14 embodiment of the invention, establishing the Bending Tolerance Rating involves
15 determining the most sensitive point on the special purpose bottom hole tool by any
16 suitable means such as finite element analysis prediction of the tool working in a curve
17 that has a 10° per 100 ft. build. This Bending Tolerance Rating is useful, for example,
18 when evaluating drill stem components made by companies such as Sperry Sun,
19 Baker, and Dyna-Dril. These companies make special purpose bottomhole assembly
20 tools used for "Measurement While Drilling" and "Logging While Drilling" and other
21 specialty subsurface functions. These bottomhole assembly tools have special
22 geometries and structural limitations that are not defined in the readily available
23 technical literature. For purposes of design analysis, the manufacturers of these

1 specialty tools will determine a Bending Tolerance Rating that may be, for example, a
2 function of the weakest structural point in their special tool. This Bending Tolerance
3 Rating will be published by the manufacturer and may be used by the drilling engineer
4 to confirm that the components can be appropriately used in the proposed drill string
5 assembly selected for drilling a particular wellbore.

BRIEF DESCRIPTION OF THE DRAWINGS

The foregoing and other features and advantages of the present invention will be best understood with reference to a detailed description of a preferred embodiment of the invention, which follows, when read in conjunction with the accompanying drawings, wherein:

Figure 1 is a flow diagram illustrating a drill string design process in accordance with one embodiment of the invention;

Figure 2 is a diagram illustrating the fatigue design review step in the process of Figure 1;

Figure 3 is a graph showing a number of plots of tension versus Curvature Index in accordance with one embodiment of the invention; and

Figure 4 is a graph showing a number of plots of hole size versus Stability Index in accordance with one embodiment of the invention.

1 DETAILED DESCRIPTION OF A SPECIFIC EMBODIMENT OF THE INVENTION

2 The disclosure that follows, in the interest of clarity, does not describe all features
3 of actual implementations of the invention. It will be appreciated that in the development
4 of any such actual implementations, as in any such project, numerous engineering
5 decisions must be made to achieve the developers' specific goals and subgoals, which
6 may vary from one implementation to another. Moreover, attention will necessarily be
7 paid to proper engineering and practices for the environment in question. It will be
8 appreciated that such an effort might be complex and time-consuming, but would
9 nevertheless be a routine undertaking for those of ordinary skill in the relevant fields.

10 Referring to Figure 1, there is shown a flow diagram of a drill string design process
11 10 carried out in accordance with one embodiment of the invention. The first step in the
12 process, represented by block 12 in Figure 1, is to perform an overload structural design.
13 Preferably, overload design is approached from the classical design standpoint. That is,
14 the loads are predicted, then components capable of carrying the loads are used. Since
15 the predictive formulas for load calculation are generally reliable, the design itself, if
16 properly executed, will be reliable.

17 Since the plan for any hole section will have many issues and needs other than
18 structure, the next step in the drill string design process 10 is to optimize the design, as
19 represented by block 14 in Figure 1. In step 14, the designer must gain maximum
20 leverage over other, non-structural needs, while maintaining a structural design that
21 meets at least minimum safety factors and design constraints.

22 Following steps 12 and 14, in accordance with the presently disclosed
23 embodiment of the invention, the next step is to review the design to mitigate fatigue

1 attack. This is represented by block 16 in Figure 1. This step is believed to set the
2 methodology of the present invention apart from prior art methodologies, which do not
3 generally take the fatigue characteristics of drill string components into account during the
4 drill string design process. As noted above, it is believed that this is the case principally
5 due to what is widely viewed as the general unreliability of data which correlate in an
6 absolute sense with the fatigue characteristics of drill string components.

7 In accordance with one aspect of the invention, on the other hand, the process 16
8 of reviewing the design for fatigue issues is a "comparative" or relative process. The
9 comparative nature of the approach is a significant feature of the present invention
10 inasmuch as it tends to overcome the problems associated with the unreliability of fatigue
11 mechanism data as an absolute indicator of the fatigue characteristics of drill string
12 components.

13 Turning to Figure 2, which illustrates the fatigue design review step 16 from Figure
14 1, the fatigue design review approach in accordance with the presently disclosed
15 embodiment involves comparing alternative designs and selecting the design
16 alternative(s) and operating approaches that (1) provide the lowest stress excursion
17 (block 22 in Figure 2); (2) provide the lowest stress concentration (block 26 in Figure 2);
18 (3) offer the best comparative fatigue life; and (4) reduce corrosion rates (block 24 in
19 Figure 2).

20 To facilitate the process of fatigue design review, the present invention involves
21 defining one or more "fatigue indices" each representing a quantification of one or more
22 parameters known to correlate to some extent with the fatigue characteristics of the drill
23 string and its constituent components. As used herein, the term "drill string component"

1 shall be interpreted broadly to mean any one or more sections or subsection(s) of an
2 overall drill string, including those section(s) in the upper drill string and those in the
3 bottomhole assembly. Further, as used herein, the term "fatigue characteristics" shall be
4 understood to mean those characteristics of a drill string component which either promote
5 or resist fatigue failure. Preferably, each fatigue index is defined such that a fatigue index
6 value as computed for a particular drill string component under particular operating
7 conditions will provide at least a relative measure by which the likelihood of fatigue for two
8 or more alternative candidate drill string components can be compared. By selecting drill
9 string components based on such relative comparisons between alternative candidate
10 components, the drill string designer is advantageously guided toward defining a drill
11 string which mitigates problems associated with fatigue damage and failure.

12 One such fatigue index is referred to herein as Curvature Index, defined as a
13 measure of the relative reduction in fatigue life caused by rotating a drill pipe tube in a
14 curved hole section, taking into account the degree of hole curvature (build/drop rate),
15 pipe size, adjusted pipe weight, grade, and axial tension in the pipe.

16 As noted above, in a practical application of the use of the Curvature Index, a
17 drilling engineer may have a choice of wellbore trajectories that may be used for
18 reaching a subsurface objective. For example, the trajectory may involve a wellbore that
19 results in a 3° per 100 ft. dog leg with 450,000 lbs tension in the drill string or the
20 wellbore may result in a 15° per 100 ft. dog leg with 100,000 lbs tension in the drill
21 string to reach the same objective. Drilling the well with a 3° per 100 ft. dog leg may be
22 less costly than drilling the well with a 15° per 100 ft. dog leg. However, the reduced
23 fatigue damage done to the drill pipe during the drilling of the 15° per 100 ft. dog leg

1 well may offset the savings associated with drilling the 3° per 100 ft. dog leg well.

2 Essentially, the Curvature Index is a non-absolute (i.e., relative) quantification of
3 the potential for fatigue resulting from subjecting a drill string component to curvature and
4 tension in a borehole, which is typically expressed in terms of degrees of curvature per
5 length of borehole, e.g., 10° per 100 feet. To calculate the Curvature Index for a drill string
6 component, the first step is to compute the tension on the drill string under analysis.
7 Those of ordinary skill in the art will appreciate that tension is computed based on various
8 factors, including the weight of the drill string and BHA components, mud volume and/or
9 mud weight, and so on.

10 Having determined the tension, which is typically expressed in units of pounds, the
11 next step in computing the Curvature Index is to calculate the stress on the drill string.
12 Those of ordinary skill will be familiar with the many factors taken into account in
13 computing stress on a drill string, among them being the amount of curvature, also
14 referred to as dog-leg severity or DLS to which the drill string is subjected.

15 In one embodiment, the stress is computed using the following methodology:
16 Consider a drill pipe tube rotating in a dogleg while it's in tension. The stress in the
17 outer fiber of the drill pipe tube caused by bending (σ_b) as it rotates in a dogleg is
18 calculated based in part on the work of Arthur Lubinski. Equations (3) and (4) were
19 obtained from Lubinski's work; however, the forms of these equations were derived to
20 suit this application. Equation (3) is used to test whether or not contact is occurring
21 between the drill pipe tube and the hole wall for a given hole curvature and axial tensile
22 load. Equation (4) is used to calculate M_o for cases in which wall contact does not occur
23 between the drill pipe tube and the hole wall. In the case of wall contact, equation (4)

will not apply. Therefore, it was necessary to derive equation (5) to handle the wall contact case. This derivation was assisted by the work of Jiang Wu, who solved a similar problem for pipe under compressive loads.

$$(1) \quad \sigma_b = \frac{D}{2I} M_o$$

Calculate c:

$$(2) \quad c = \frac{1}{R_c}$$

Calculate c_c :

$$(3) \quad c_c = \frac{D_{TJ} - D}{L^2} \frac{(KL) \sinh(KL)}{2 - 2 \cosh(KL) + (KL) \sinh(KL)} + \frac{w_b L^2 \sin(\theta)}{EI (KL)^2}$$

If c is less than c_c , then the pipe does not contact the hole wall and M_o is given by equation (4). If c is greater than or equal to c_c , then the pipe does contact the hole wall and M_o is given by equation (5).

$$(4) \quad M_o = \frac{KL}{\tanh(KL)} \left[E I c - \frac{w_b L^2 \sin(\theta)}{(KL)^2} \right] + \frac{w_b L^2 \sin(\theta)}{(KL)^2}$$

$$(5) \quad M_o = \frac{w_b L^2 \sin(\theta)}{(KL)^2} + \frac{(KL/2)}{\tanh(KL/2)} \left[E I c - \frac{w_b L^2 \sin(\theta)}{(KL)^2} \right] + \frac{2 \cdot (KL/2)^2 \tanh(KL/2)}{(KL/2) - \tanh(KL/2)} \frac{EI \cdot r_c}{L^2}$$

$$(6) \quad K = \sqrt{\frac{T}{EI}}$$

$$(7) \quad r_c = \frac{D_{TJ} - D}{2}$$

Next, the axial stress (σ_a) in the drill pipe tube is calculated.

$$(8) \quad \sigma_a = \frac{T}{A}$$

$$(9) \quad A = 0.7854 (D^2 - d^2)$$

1 Nomenclature for stress calculations:

2 A = Drill pipe tube cross sectional area, (in²)

3 D = Drill pipe tube outer diameter, (in)

4 D_{TJ} = Drill pipe tool joint outer diameter, (in)

5 d = Drill pipe tube inner diameter, (in)

6 E = Young's modulus, (psi)

7 I = Moment of inertia of drill pipe tube, (in⁴)

8 L = Half the drill pipe tube length, (in)

9 M_o = Bending moment on the drill pipe tube at the tool joint, (in-lbs)

10 θ = Average inclination angle across the drill pipe tube, (radians)

11 T = Axial tensile load, (lbs)

12 R_c = Radius of curvature of hole wall, (in)

13 c = Curvature of hole wall, (in⁻¹)

14 c_c = Critical curvature of hole wall, (in⁻¹) (hole wall curvature required for the

15 middle of the drill pipe tube to just contact the hole wall for a given axial tensile load)

16 w_b = Buoyed weight per unit length, (lb/in)

17 σ_a = Axial stress, (psi)

18 σ_b = Bending stress, (psi)

19
20 The foregoing methodology for computation of stress in the drill string is derived
21 from the work of Arthur Lubinski, "Maximum Permissible Dog-Legs in Rotary Boreholes,"
22 SPE 1960, revised 1961, which work is hereby incorporated by reference herein.
23 Methodologies for stress calculation are also discussed in T H Hill Associates, Inc., DS-

1 1, *Drill Stem Design and Operation*, Third edition, Jan. 2003; Hill, T.H., Ellis, S., Lee, K.,
2 Reynolds, N., Zheng, N., "An Innovative Design Approach to Reduce Drillstring
3 Fatigue," IADC/SPE 87188, 2004; and Jiang Wu, "Drill Pipe Bending and Fatigue in
4 Rotary Drilling of Horizontal Wells," SPE 37353, 1996, each of which being hereby
5 incorporated by reference in their entireties. It is believed that those of ordinary skill in
6 the art will be familiar with still other methodologies for computation of stress in drill
7 strings, and the selection and use of a particular methodology is not believed to be a
8 critical consideration in the practice of the present invention.

9 After computing the stress, which is typically expressed in units of pounds per
10 square inch, the next step in computing the Curvature index is to compute a "fatigue
11 life" value. In accordance with one embodiment of the invention, the fatigue life value is
12 determined by assuming that a stress fracture of an arbitrary, predetermined size is
13 present in the drill string. Those of ordinary skill in the art will appreciate that the various
14 tools and methods for identifying and locating stress fractures in drill string components
15 are inherently limited, such that stress fractures below a certain size are essentially
16 undetectable using conventional techniques. Accordingly, in one embodiment of the
17 invention, the fatigue life value is computed based on the assumption that a stress
18 fracture just small enough to be undetectable using conventional techniques is present
19 in the drill string.

20 Based on this assumption, the fatigue life value is computed using any of various
21 well-known methodologies. In the presently preferred embodiment, the well-known
22 Forman Crack Growth Model is applied. This model is described in further detail in

Campbell, J.E., Gerberich, W.W., and Underwood, J.H., *Application of Fracture Mechanics for Selection of Metallic Structural Materials*, ASM, 1982, p. 35.

Summarizing, the Forman Crack Growth Model allows for the computation of crack growth rate da/dN (expressed for example, in units of inches per stress cycle), as follows:

$$\frac{da}{dN} = \frac{C\Delta K^n}{(1-R)K_{IC} - \Delta K}$$

$$\Delta K = K_{\max} - K_{\min}$$

$$K_{\max} = \sigma_{\text{axial}} \sqrt{\pi a} F_{\text{axial}} + \sigma_{\text{bending}} \sqrt{\pi a} F_{\text{bending}}$$

$$K_{\min} = \sigma_{\text{axial}} \sqrt{\pi a} F_{\text{axial}} - \sigma_{\text{bending}} \sqrt{\pi a} F_{\text{bending}}$$

a = crack depth, (in)

C = Forman Crack Growth Model empirical coefficient

da/dN = crack growth rate, (in/cycle)

F_{axial} = stress intensity geometry and crack shape correction factor for axial loads

F_{bending} = stress intensity geometry and crack shape correction factor for bending

loads

K_{IC} = critical stress intensity factor, (ksi $\sqrt{\text{in}}$)

K_{\max} = maximum stress intensity factor, (ksi $\sqrt{\text{in}}$)

K_{\min} = minimum stress intensity factor, (ksi $\sqrt{\text{in}}$)

n = Forman Crack Growth Model empirical coefficient

R = ratio of maximum stress to minimum stress

σ_{axial} = axial stress

1 σ_{bending} = bending stress

2
3 Those of ordinary skill in the art will appreciate that the "fatigue life" value is
4 essentially merely a rough estimation of expected time to fatigue failure in the drill string
5 component for which this value is derived.

6 In the presently preferred embodiment of the invention, the fatigue life value is
7 subjected to a predetermined constant multiplier value to derive the Curvature Index.

8 In view of the foregoing, those of ordinary skill in the art will appreciate that
9 deriving the Curvature Index in accordance with the presently disclosed embodiment
10 involves essentially processing certain known parameters about the drill string and its
11 environment, based on certain benchmark assumptions, such as DLS, fracture sizes,
12 and so on. As a consequence, the Curvature Index admits to presentation to drill string
13 designers in relatively simple formats, making comparison of the Curvature Index for
14 alternative drill string components and/or for alternative wellbore conditions efficient.

15 Figure 3 is one example of how the Curvature Index data may be presented to a
16 drill string designer. In the graph of Figure 3, units of tension extend along the
17 horizontal axis, while the Curvature Index values extend along the vertical axis. In the
18 example graph of Figure 3, each numbered plot (1, 2, 3, ... 30) corresponds to a
19 different dog-leg severity (DLS), and the graph of Figure 3 provides Curvature Index
20 data for a particular drill string component (5-inch drill pipe, S135 Premium Class, 6-
21 5/16-in tool joint, etc...). To utilize the graph of Figure 3, a drill string designer would
22 need only identify the tension on the drill string and the DLS, and then locate the
23 intersection of that tension value with the corresponding DLS plot.

1 Of course, separate graphs like the exemplary one of Figure 3 would preferably
2 be provided for different combinations of pipe sizes, pipe types, tool joint sizes, and so
3 on. With reference to such data, a drill string designer can make a comparative
4 assessment between alternative drill string components for a given drilling operation to
5 determine, as between any two or more design alternatives, which alternative appears
6 optimal from the standpoint of fatigue minimization. It is important to note that the
7 Curvature Index data is intended to provide only comparative information about fatigue
8 resistance as between two or more possible drill string design alternatives, as opposed
9 to absolute data about the fatigue resistance of a particular design.

10 Another fatigue index utilized in accordance with the practice of the present
11 invention is the Stability Index, which like the Curvature Index is a comparative or
12 relative measure of fatigue life of bottomhole assemblies (BHAs), that are
13 simultaneously subjected to buckling and rotation. Like the Curvature Index, the
14 Stability Index is useful for comparing one design from another to select the alternative
15 most favorable from a fatigue standpoint. Once the designer has selected a bottomhole
16 design, the Stability Index can be used to estimate the fatigue resistance of the BHA for
17 such purposes as setting inspection intervals and the like.

18 Computation of the Stability Index in accordance with the presently disclosed
19 embodiment of the invention involves steps somewhat similar to those involved in
20 computation of the Curvature Index. First, conventional finite element analysis (FEA)
21 techniques are used to compute the stress in the BHA. Use of FEA techniques for this
22 purpose is very common in the art, and it is not believed that a detailed description of
23 this process is necessary for the purposes of the present disclosure.

1 Having computed the BHA stress value, a relative "fatigue life" value can be
2 computed using the Forman Crack Growth Model described above with reference to the
3 Curvature Index. From the fatigue life value, the Stability Index value can be derived.

4 Stability Index data for various alternative BHA configurations can be presented
5 to and used by a drill string designer in the form shown in the example of Figure 4. In
6 the graph of Figure 4, hole size values extend along the horizontal axis, and the various
7 plots correspond to different sizes of drill collars. For a given hole size and drill collar
8 size, the Stability Index can be read off of the vertical axis.

9 As with the Curvature Index, the Stability Index is intended to provide
10 comparative or relative data between alternative BHA configurations, such that a drill
11 string designer can efficiently compare, from the standpoint of fatigue failure, the
12 relative merits of alternative drill string/BHA designs.

13 Another comparison factor used in the drill string design methodology of
14 the present invention is a "Bending Tolerance Rating". The Bending Tolerance Rating
15 is used to assist in the selection of bottomhole assembly components that may have an
16 unusual or special configuration with structural capabilities and limitations that are not
17 commonly known to the design engineer. In a preferred form of the Invention,
18 establishing the Bending Tolerance Rating involves determining the most sensitive
19 point on a special purpose bottom hole assembly tool by any suitable means such as
20 finite element analysis prediction of the tool working in a curve that has a 10° per 100
21 ft. build. This Bending Tolerance Rating is useful, for example, when evaluating drill
22 stem components made by companies such as Sperry Sun, Baker, and Dyna-Dril.
23 These companies make special purpose bottomhole assembly tools used for

1 "Measurement While Drilling" and "Logging While Drilling" and other specialty
2 subsurface functions. These bottomhole assembly tools have special geometries and
3 structural limitations that are not defined in the readily available technical literature.

4 For purposes of design analysis, the manufacturers of these specialty bottom
5 hole assembly tools will determine a Bending Tolerance Rating that may be, for
6 example, a function of the weakest structural point in their special tool. This Bending
7 Tolerance Rating can be published by the manufacturer and may be used by the drilling
8 engineer to confirm that the components can be appropriately used in the proposed drill
9 string assembly selected for drilling a particular wellbore.

10 The following Table 1 illustrates one example of a Bending Tolerance Rating
11 schema in accordance with one embodiment of the invention.

TABLE 1

BTR	Maximum Stress in Body (σ_{\max})
1	$\sigma_{\max} \leq 0.25 \cdot \text{MYS}$
2	$0.25 \cdot \text{MYS} < \sigma_{\max} \leq 0.4 \cdot \text{MYS}$
3	$\sigma_{\max} > 0.4 \cdot \text{MYS}$

12
13 In the example of Table 1, Bending Tolerance Ratings are defined for various
14 maximum stress ranges as a function of the material yield strength (MYS). As a
15 benchmark, finite element analysis can be employed to determine the maximum stress
16 σ_{\max} in the body of a tool (including stress concentrators) for bending in a
17 predetermined dog-leg, for example, 10° per 100 feet. The BTR for the tool is then read
18 out of Table 1 based on this maximum stress. In the example of Table 1, a tool would
19 be assigned a BTR of 1 if FEA shows that the maximum stress in the curvature is less
20 than or equal to 25% of the tool's material yield strength. On the other hand, a tool
21 would be assigned a BTR of 2 if FEA shows that the maximum stress in the curvature is

1 between 25% and 40% of the tool's MYS, and a BTR of 3 if the stress is greater than
2 40% of the tool's MYS. Such a rating system provides a convenient way for drill string
3 designers to specify to suppliers minimum acceptable bending tolerances for drill string
4 components.

5 The exemplary embodiment of Table 1 above reflects a three-tiered rating
6 system. Those of ordinary skill in the art having the benefit of this disclosure will
7 appreciate of course, that rating systems with fewer or more rating levels may be
8 defined in alternative embodiments.

9 From the foregoing description, those of ordinary skill in the art will appreciate
10 how the methodology of the present invention may be put into practice in the design of
11 a drill string. First, of course, the drill string designer must establish one or more
12 operational objectives in the construction of a wellbore segment, and determining
13 limiting parameters of the wellbore segment to be constructed. These may include, for
14 example, bore size, DLS, pipe type(s) and size(s), and so on.

15 Next, the designer determines a selected first working parameter of a plurality of
16 first components of a first type of equipment available to construct the wellbore
17 segment. In the disclosed embodiment, the first working parameter may be curvature or
18 stability.

19 The present invention provides a comparison factor for each of two or more of
20 the first components, based on the selected working parameter of the first components.
21 This enables to the designer to compare the respective comparison factors of the first
22 components, and to select a first component from said plurality of first components,
23 using the comparison of comparison factors, to best meet said operational objectives in

1 the construction of the wellbore segment.

2 Because at least two different indices may be established for characterizing a
3 drillstring component, the methodology of the present invention can further involve
4 determining a second working parameter for two or more second components selected
5 from a plurality of available second components of a second type of equipment
6 available to construct the wellbore segment.

7 The invention provides a comparison factor for each of said two or more second
8 components using the second working parameter, enabling the designer to compare
9 the comparison factors of said second components, and selecting first and second
10 components, to best meet the operational objectives, based on comparing the
11 comparison factors.

12 From the foregoing, it will be apparent to those of ordinary skill in the art that a
13 method for constructing a drill string has been disclosed which adopts a comparative
14 selection process for minimizing the likelihood of fatigue damage and failure in the
15 resulting drill string. Although specific embodiments of the invention have been
16 disclosed, it is to be understood that this has been done solely for the purposes of
17 describing various aspects of the invention, and is not intended to be limiting with
18 respect to the scope of the invention as defined by the claims that follow. It is
19 contemplated that various substitutions, alterations, and/or modifications, including but
20 not limited to those design alternatives specifically mentioned herein, may be made to
21 the disclosed embodiments without departing from the spirit and scope of the invention
22 as defined in the claims.